Bonterra
Energy Income Trust

2002 ANNUAL REPORT

TRUST PROFILE

Bonterra Energy Income Trust. (TSE symbol - BNE.UN) is an energy income trust that develops and produces oil and natural gas in the Provinces of Alberta and Saskatchewan.

The Trust's business strategy is to strive to maximize unitholders value by applying long-term growth objectives. The Trust's primary objective is to combine its oil and gas production technical strengths with planned business strategies to generate above average results and returns for our unitholders.

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NOTICE OF ANNUAL MEETING

The Annual Meeting of Unitholders will be held on Monday, June 16, 2003, in the Lakeview Endrooms at the Westin Hotel, 320 Fourth Avenue S.W., Calgary, Alberta, at 11:00 a.m. (Calgary time).

Bonterra
Energy Income Trust

HIGHLIGHTS

	2002	2001 (Note 1)
FINANCIAL ($000, except $ per unit)		
Revenue - oil and gas (net of royalties)	$ 36,424	$ 11,257
Distributions per Unit	1.43	0.80
Cash Flow from Operations	19,458	6,446
Per Unit Fully Diluted	1.50	0.74
Net Earnings	12,474	5,366
Per Unit Fully Diluted	0.96	0.62
Capital Expenditures and Acquisitions	52,751	1,329
Outstanding Debt	18,357	7,890
Unitholders' Equity	41,892	11,388
Units Outstanding (weighted average) (000's)	12,979	8,692
OPERATIONS		
Oil and Liquids (barrels per day)	2,464	1,531
Average Price ($ per barrel)	$ 37.35	$ 38.05
Natural Gas (MCF per day)	4,287	1,408
Average Price ($ per MCF)	$ 4.10	$ 4.55
RESERVES (proven developed producing)		
Oil and Liquids (barrels in 000's)	11,830	7,069
Natural Gas (MCF in 000's)	15,278	6,320

Note 1

Bonterra Energy Income Trust was formed on July 1, 2001. Comparative financial and operational figures listed above represent operations from this date to December 31, 2001.

REPORT TO UNITHOLDERS

Bonterra Energy Income Trust ("Bonterra") is pleased to report its operational and financial results for the year. The Trust had a successful growth year and its annual distributions and capital appreciation resulted in a rate of return to unitholders of 75 percent, far exceeding the return of most trusts and corporations.

Operations

Bonterra's production is ideally suited for a trust. Approximately 75 percent of its production is mainly light, sweet gravity crude and liquids, and the remaining 25 percent natural gas is sweet long-life production. The life index for the Trust's proven producing reserves is approximately 12 years, which is significantly higher than most other trusts. It should also be noted that Bonterra's life index includes only proven producing reserves. Most other trusts life indexes include proven non-producing and probables as well (established reserves).

The long-life index allows the Trust to distribute a higher percentage of its cash flow to Unitholders rather than using it for capital expenditures to maintain production volumes. Bonterra's annual decline rate is approximately eight percent.

Production volumes for the 2002 year averaged 3,179 barrel of oil equivalents (BOE's) per day compared to 1,766 BOE's per day in 2001. The December 31, 2002 exit production was approximately 3,400 BOE's per day.

Financial

Bonterra's distribution for 2002 was $1.43 compared to $0.80 for the six-month period ended December 31, 2001, of which 69.82 (2001 - 64.5) percent is taxable and 30.18 (2001 - 35.5) percent is a return of capital.

Gross revenue from commodity sales was $40,198,000 in 2002 compared to $11,970,000 for the preceding six month period. Commodity prices were $37.35 per barrel of oil and natural gas liquids, and $4.10 per MCF for natural gas.

At year-end Bonterra's long-term debt was approximately $18,357,000, which is approximately 11 months cash flow on an annualized basis. This debt to cash flow level is much lower than most other trust debt to cash flow levels.

Outlook

The objectives for the Trust are to increase its production volumes in the future by developing its existing properties and by acquiring additional production. The high commodity prices do make it more difficult to acquire properties at prices that will benefit the Trust in the future, however, we still feel that we will be successful in making some strategic acquisitions in 2003.

In 2003 Bonterra will be aggressively evaluating potential production from coal beds and other shallow natural gas horizons in the Pembina area of Alberta. The Trust will be testing a number of wells to determine production volumes of natural gas from the shallow coal beds to better assess the economic potential for this type of production. Further information about results will continue to be released on a timely basis.

The Trust is optimistic that if commodity prices are reasonable, the Trust should be able to continue to provide high returns and additional capital appreciation. It should be noted that since Bonterra Energy Corp. (predecessor to the Trust) was incorporated and listed publicly in mid 1998, for every $1.00 invested at that time, it would now be worth approximately $21.24 plus the investor would have received $5.20 in cash.

The Board of Directors of the operating company and management wish to thank the unitholders for their continued support, and the staff for the continued significant contribution made by them.

Submitted on behalf of the Board of Directors,

George F. Fink
President, CEO and Director

REVIEW OF OPERATIONS

Reserves

The Trust engaged the services of an independent engineering firm to prepare a reserve evaluation with an effective date of January 1, 2003. The reserves are located in the Provinces of Alberta and Saskatchewan. The majority of the Trust's production is comprised of light sweet crude, which results in higher oil prices, and better marketing opportunities. The Trust's main oil producing areas are located in the Pembina area of Alberta and Dodsland area of Saskatchewan. Oil and natural gas established reserve estimates at December 31, 2002, before royalties, are as follows:

	Crude Oil and Liquids (MBbls)		Natural Gas (MMCF)	
	Proven	Probable	Proven	Probable
December 31, 2001	7,069	84	6,320	36
Comstate Resources Income Trust				
Acquisition	4,228	374	9,585	281
Production	(899)	–	(1,565)	–
Other acquisitions	383	–	764	–
Drilling additions	36	–	1,540	–
Evaluation adjustments to reserves	1,013	(39)	(1,366)	303
December 31, 2002	11,830	419	15,278	620
Life index (years) - December 31, 2002	13.2		9.8	

ESTIMATED PRESENT WORTH OF FUTURE NET PRODUCTION REVENUE

		Discounted at the rate of		
($ thousands)	Undiscounted	10%	15%	20%
Proven developed producing reserves	222,946	105,571	85,335	72,432
Probable reserves, risked at 50%	10,645	1,722	1,032	692
Proven and probable reserves at December 31, 2002	233,591	107,293	86,367	73,124
Proven and probable reserves at December 31, 2001	125,553	59,205	47,430	39,892

Commodity prices used in the above calculations of reserves are as follows:

Year	Edmonton Par Price (Cdn $ per barrel)	Alberta Index Plantgate (Cdn $ per MCF)	Propane (Cdn $ per barrel)	Butane (Cdn $ per barrel)	Pentane (Cdn $ per barrel)
2003	38.43	5.72	21.53	24.35	39.36
2004	34.82	5.21	19.50	22.06	35.66
2005	32.22	4.60	18.05	20.42	33.00
2006	32.78	4.27	18.36	20.77	33.57
2007	33.90	4.42	18.99	21.48	34.72
2008	34.42	4.48	19.28	21.81	35.25
2009	35.58	4.67	19.93	22.54	36.44
2010	36.13	4.75	20.24	22.89	37.00
2011	36.69	4.84	20.55	23.24	37.57
2012	37.26	4.94	20.87	23.60	38.16
2013	37.83	5.03	21.19	23.97	38.75
2014	38.42	5.12	21.52	24.34	39.35

Crude oil, natural gas and liquid prices escalate at 1.5% per year thereafter.

Production

The following table provides a summary of production volumes from our main producing areas.

	2002		2001	
	Oil and NGL (Bbls/day)	Natural Gas (MCF/day)	Oil and NGL (Bbls/day)	Natural Gas (MCF/day)
Pembina, Alberta	1,812	2,972	972	986
Dodsland, Saskatchewan	474	305	500	354
Pinto, Saskatchewan	51	50	59	68
Redwater, Alberta	43	95	–	–
Midale, Saskatchewan	45	20	–	–
Other	39	845	–	–
	2,464	4,287	1,531	1,408

Land Holdings

The Trust's holdings of petroleum and natural gas leases and rights are as follows:

	2002		2001	
	Gross Acres	Net Acres	Gross Acres	Net Acres
Alberta	111,200	64,020	36,034	28,080
Saskatchewan	32,584	19,524	29,630	17,768
	143,784	83,544	65,664	45,848

Petroleum and Natural Gas Capital Expenditures

The following table summarizes petroleum and natural gas capital expenditures incurred by the Trust on acquisitions, land, seismic, exploration and development drilling and production facilities for the periods:

	2002	2001
Comstate Resources Income Trust acquisition	$ 47,697,000	$ –
Other acquisitions	2,333,000	–
Exploration and development costs	2,239,000	964,000
Pipeline projects	481,000	293,000
Seismic	1,000	10,000
Land costs	–	62,000
Net petroleum and natural gas capital expenditures	$ 52,751,000	$ 1,329,000

Drilling History

The following table summarizes the Trust's gross and net drilling activity and success :

2002	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude Oil	1	.13	–	–	1	0.13
Natural Gas	1	1.00	9	7.25	10	8.25
Dry	–	–	–	–	–	–
Total	2	1.13	9	7.25	11	8.38
Success rate	100%	100%	100%	100%	100%	100%

2001	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude Oil	2	2.00	–	–	2	2.00
Natural Gas	1	.97	7	6	8	6.97
Dry	–	–	–	–	–	–
Total	3	2.97	7	6	10	8.97
Success rate	100%	100%	100%	100%	100%	100%

Market Performance

CUMULATIVE TOTAL RETURN ON $100 INVESTMENT

Bonterra Energy Income Trust (notes 1 & 2)

JULY 1998	$100
DEC 1998	$245
DEC 1999	$550
DEC 2000	$900
DEC 2001	$1,512
DEC 2002	$2,644

Note 1: Includes the results of Bonterra Energy Corp. prior to July 1, 2001

Note 2: Includes distributions of $2.23 since becoming a trust.

PROPERTY DISCUSSIONS

Bonterra has an excellent asset base consisting of long life, low risk and predictable reserves with upside and management that has proven it can manage these high quality assets to generate long term value. Our producing properties are located in the Pembina area of Alberta, the East Central area of Alberta, the Dodsland area in southwest Saskatchewan, and the southeast area of Saskatchewan. Bonterra continues to acquire exploration lands in the Pembina area of Alberta, is pursuing shallow gas exploration in Central Alberta and reviews and assesses producing and non-producing properties for acquisitions on an ongoing basis in various areas in Western Canada.

Pembina Area, West Central Alberta

The Pembina field is the largest conventional oil field in Canada and our most significant producing area. Our production is predominately predictable, long life, low decline and high quality light oil from the Cardium formation that is located at a depth of approximately 5,000 feet. Bonterra operates approximately 85 percent of its production in this large core area which allows for significant operating efficiencies. The property contains approximately 309 gross (265.2 net) operated producing wells with an 86 percent average working interest and 135 gross (21.5 net) non-operated producing wells with an approximate 16 percent average working interest.

Our large land holdings and strong infrastructure position provides a strong base to exploit a range of low risk development and exploration opportunities. Even though the Pembina area is considered a mature field it is proving to be a significant area for multi-zone

oil and natural gas exploration. The Trust has managed to replace produced reserves in the area through drilling as well as through key acquisitions.

Bonterra is also producing from the Belly River formation. The Belly River produces high quality light sweet oil from a depth of approximately 3,600 feet. There is potential to increase production from the Cardium and Belly River formations through infill drilling in select areas of the field. This program has been initiated on an experimental basis in 2003.

Bonterra has been able to increase natural gas production and reserves by drilling multi-zone shallow gas wells into the Edmonton and Paskapoo formations. The Trust is targeting several productive sands that range in depth from 900 to 2,400 feet. Bonterra will continue to build on our previous exploration success in the area and develop these low cost shallow natural gas reserves.

Bonterra has been conducting tests to evaluate the feasibility of coal bed methane (CBM) production with encouraging initial results. This year two wells were assigned conservative proved producing reserves by an independent engineering company. During 2003 the Trust plans to try to build on this initial success and expand these reserves. Bonterra has extensive prospective land holdings near existing operated infrastructure in the area. CBM has the potential to add significant low risk production and reserves and the Trust is aggressively pursuing this opportunity.

Dodsland Area, Southwest Saskatchewan

The Dodsland properties produce light sweet gravity oil and solution gas from the Viking formation at a depth of approximately 2,300 feet. Bonterra now operates approximately 426 gross (374 net) wells with an average working interest of 88 percent.

This is low rate stable production so cost control and hedge programs are important focuses of our operating strategy in this area. The Trust is continually reviewing different operating practices and improved technology that may improve the profitability of the property. Bonterra does not have an abandonment or reclamation liability for this property because under terms of an agreement Bonterra has an option to transfer uneconomic wells to the previous owner of the property.

Southeast Saskatchewan

The southeast properties produce slightly sour high gravity oil and solution gas from the Midale formation. The Trust has an average working interest of approximately 86 percent in the area. Bonterra continues to evaluate this area to determine if further optimization programs may increase overall profitability of the properties.

Other

Bonterra has varying interests in other producing and non-producing properties in various other areas of Alberta and Saskatchewan. Most of these properties are long term producers and may provide opportunities for increased interests in the future.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This report is a review of the operations, current financial position and outlook for the Trust and should be read in conjunction with the audited financial statements for the fiscal year ended December 31, 2002, together with the notes related thereto.

Quarterly Comparisons

	2002				2001	
	4th	3rd	2nd	1st	2nd	1st
Financial ($000, except $ per unit)						
Revenue - oil and gas (net of royalties)	$ 9,781	$ 10,035	$ 9,128	$ 7,480	$ 5,386	$ 5,871
Cash Flow from Operations	5,515	5,157	4,835	3,951	3,058	3,388
Per Unit Diluted	0.42	0.40	0.37	0.31	0.35	0.39
Net Earnings	4,043	2,716	3,261	2,454	2,186	3,180
Per Unit Diluted	0.31	0.21	0.25	0.19	0.25	0.37
Capital Expenditures and Acquisitions	808	2,673	414	48,856	1372	(43)
Outstanding Loans	18,357	18,226	16,756	16,270	7,890	7,299
Unitholders' Equity	41,892	44,266	46,362	48,181	11,388	13,548
Operations						
Oil and Liquids (barrels per day)	2,571	2,600	2,341	2,175	1,502	1,560
Natural Gas (MCF per day)	4,605	4,953	3,787	3,159	1,548	1,268

Production

The Trust's 2002 average production of barrels of oil equivalent (BOE) was 3,179 (2001 - 1,766) barrels per day. Production of oil and natural gas liquids was 2,464 (2001 - 1,531) barrels per day. The Trust's natural gas production in 2002 averaged 4,287 (2001 - 1,408) MCF per day. Production increases were predominantly due to the Trust's merger with Comstate Resources Income Trust on February 1, 2002. The combined production rate at the date of merger was 3,123 BOE's per day.

Through a combination of our shallow gas drilling, acquisitions and pipeline tie-ins, the Trust was able not only to replace its natural decline of approximately eight percent but also increase our production during 2002. This was accomplished without issuing any additional trust units and only modestly increasing our debt level. Our exit production for 2002 is approximately 3,400 BOE's per day.

Revenue

Gross revenue from petroleum and natural gas sales was $40,198,000 (2001 - $11,970,000). The average price received for crude oil and natural gas liquids including hedging, was $37.35 (2001 - $38.05) per barrel and $4.10 (2001 - $4.55) per MCF of natural gas. Over 95 percent of the Trust's crude oil production consists of light sweet crude with nominal quality and transportation adjustments. In addition, our natural gas production consists primarily of dry sweet natural gas.

Royalties

Royalties paid by the Trust consist primarily of Crown royalties paid to the Provinces of Alberta and Saskatchewan. During the fiscal period ended December 31, 2002 the Trust paid $2,995,000 (2001 - $593,000) in Crown royalties and $778,000 (2001 - $119,000) in freehold royalties, gross overriding royalties and net carried interests. The majority of the Trust's wells are low productivity wells and therefore have low Crown royalty rates. The Trust's average Crown royalty rate is approximately seven percent and approximately two percent for other royalties. The Trust is eligible for Alberta Crown Royalty rebates for Alberta production from a small amount of its purchased wells as well as on newly drilled wells.

Production Costs

Production costs totalled $15,226,000 in 2002 compared to $4,098,000 in the six month period that the Trust operated for in 2001. On a BOE basis, 2002 operating costs were $13.12 compared to $12.61 for the 2001 six month period. The increased costs on a BOE basis are mainly due to more stringent gathering system testing and maintenance required by the Alberta Energy and Utilities Board, increases in municipal taxes, start-up costs of new wells and related facility costs, facility maintenance, and increased costs in non-operated properties.

Management is currently examining means of reducing operating costs. Operating costs in the $12 to $13 per BOE range are expected due to the number of low productivity oil wells the Trust owns expecially in the Dodsland area of Saskatchewan. As the Trust develops its shallow natural gas potential, the average costs per BOE will decline. The high operating costs for the Trust are substantially offset by low royalty rates of approximately nine percent, which is much lower than industry average for conventional production and results in high cash net backs on a combined basis.

General and Administrative Expense

General and administrative expenses were $1,298,000 in 2002 compared to $568,000 in the 2001 six month period. On a BOE basis, general and administrative expenses in 2002 averaged $1.12 per BOE compared to $1.75 per BOE in 2001.

The Trust had entered into a management agreement with Comstate Resources Ltd. to provide field operations, management and general office services. Fees charged for field operations were charged on a per well basis. Fees associated with well operations were charged to production costs as incurred. Fees for management and general office services consisted of $30,000 per month plus three percent of before tax net income. Effective February 1, 2002, with the merger of the Trust with Comstate Resources Income Trust, Comstate Resources Ltd. became a wholly owned subsidiary of the Trust and the Trust is no longer charged a management fee.

Interest Expense

Interest expense for the 2002 fiscal year of the Trust was $671,000 (2001 - $200,000). Interest rate charges during the period on the outstanding debt averaged approximately four (2001 - 4.85) percent. The Trust maintained an average outstanding debt balance of approximately $16,500,000.

The Trust has the ability to use Bankers Acceptances (BA's) as part of its loan facility. Interest charges on BA's are generally one third percent lower than that charged on the general loan account. The Trust also has an $8,000,000 balance owing to Comaplex

Minerals Corp., a former subsidiary of Comstate Resources Ltd. The loan carries an interest rate of Royal Bank of Canada prime less three quarters of a percent.

Gain on Disposal of Property

On September 28, 2001, the Trust's subsidiary, Novitas Energy Ltd. (Novitas), went public on the Canadian Venture Exchange (since renamed TSX Venture Exchange) and ceased to be a subsidiary. With Novitas no longer being a subsidiary of the Trust the gain on disposition of $294,000 from the sale of an oil and gas property from Bonterra to Novitas (original transaction of Novitas) had to be adjusted. The gain represents the difference between the Trust's book value of the property and the fair value of the property sold to Novitas for cash proceeds of $650,000.

Depletion, Depreciation, Future Site Restoration and Dry Hole Costs

The Trust follows the successful efforts method of accounting for petroleum and natural gas exploration and development costs. Under this method, the costs associated with dry holes are charged to operations. For intangible capital costs that result in the addition of reserves, the Trust depletes its oil and natural gas intangible assets using the unit-of-production basis by field. For tangible assets such as well equipment, a life span of ten years is estimated and the related tangible costs are depreciated at one tenth of original cost per year. Provisions are made for future site restoration based on management's estimation of abandonment requirements using current costs and amortized on a unit-of-production basis by field.

For the fiscal year ending December 31, 2002, the Trust expensed $7,570,000 for the above-described items. The increase of $5,772,000 over the 2001 balance is due primarily to provisions on assets acquired from Comstate Resources Income Trust as well as a full year of operations.

The business combination of the Trust and Comstate Resources Income Trust was treated as a purchase which resulted in an increase of $34,625,000 to the carrying value of the assets of Comstate Resources Income Trust.

The Trust currently has an estimated reserve life of 12.4 years based on a third party engineering report dated January 1, 2003. Therefore, depletion and depreciation expense of the existing assets, excluding dry hole costs, will be less than 10 percent for 2003. The Trust's coal bed development program has the potential to increase the Trusts current reserve life as natural gas production from this type of formation generally has a reserve life beyond 20 years.

Income Taxes

The Trust is required to allocate all taxable income to its unitholders and as such will not incur any current taxes. The Trust operates its oil and gas interests through its 100 percent owned subsidiaries Bonterra Energy Corp. (Bonterra Corp.) and Comstate Resources Ltd. (Comstate Ltd.) With the restructuring into an income trust, Bonterra Corp. and Comstate Ltd. pay the majority of their income to the Trust through interest and royalty payments which are deductible for income tax purposes. For the year ended December 31, 2002 and the period July 1 to December 31, 2001, Bonterra Corp. and Comstate Ltd. both paid to the Trust sufficient royalty and interest payments to eliminate all their taxable income. The current tax amount represents a recovery of previous period's tax paid by Comstate Ltd.

Future tax provision relates to the future taxes that

exist within Bonterra Corp. and Comstate Ltd. The liability on the balance sheet and the corresponding income recovery relates to temporary differences existing between Bonterra Corp's. and Comstate Ltd.'s book value of its assets and its remaining tax pools.

Net Earnings

The Trust is extremely pleased to report net earnings of $12,474,000 for the fiscal year ended December 31, 2002. This was an increase of $7,108,000 over the Trusts 2001 net income of $5,366,000. On a per unit basis, the Trust recorded net earnings per unit in 2002 of $0.96 verses $0.62 in the 2001 fiscal period. This represents a return on unitholders' equity of approximately 29.8 percent during the 2002 fiscal year based on year end unitholders' equity.

The Trust has an average cost for its oil and gas assets of $4.82 per BOE of proven developed producing reserves resulting in low depletion and depreciation provisions. This combined with low administration and interest expenses all contribute towards the significant net earnings.

Cash Flow from Operations

Cash flow from operations for the fiscal year ending December 31, 2002 was $19,458,000 compared to $6,446,000 for the six month fiscal period ended December 31, 2001. The increase was primarily due to the acquisition of Comstate Resources Income Trust and the full year of operations.

Cash Netback

The following table illustrates the Trust's cash netback:

$ per BOE	2002	2001
Production volumes (BOE)	1,160,152	324,893
Gross production revenue	$ 34.65	$ 36.84
Royalties	(3.12)	(2.19)
Field operating	(13.12)	(12.61)
Field netback	18.41	22.04
General and administrative	(1.12)	(1.75)
Interest	(0.58)	(0.62)
Cash netback	$ 16.71	$ 19.67

Liquidity and Capital Resources

During the 2002 fiscal year the Trust participated in drilling 11 gross (8.38 net) wells at a total cost of $2,239,000. Of these wells, one (.13 net) oil wells and 8 (6.25 net) gas wells were completed and on production by December 31, 2002. The remaining two wells are waiting for pipeline tie-in which is anticipated to occur prior to June 2003.

The Trust currently has plans to drill 30 (net of approximately 20) shallow gas (including coal bed methane) wells in 2003. Bonterra is currently seeking approval for reduced drill spacing units in respect of our coal bed methane development. This approval may result in increased drilling activity in 2003. The currently planned drill program will be funded out of current cash flow and should at least replace our anticipated 2003 natural production decline. Any increases in the Trust's capital expenditures program will be subject to drilling results from existing programs and the Trust's working capital position at the time.

The Trust is continuing in its efforts to acquire existing production through either property or corporate acquisitions. Acquisitions are being examined with the underlying consideration being enhancing value to our existing unitholders.

At December 31, 2002 the Trust had long-term debt of $18,357,000 (2001 - $7,890,000). The increase was due partially to the merger with Comstate Resources Income Trust as well as management's decision to

increase the Trust's debt leverage. The Trust still maintains a debt to cash flow ratio of less than one year.

The Trust has a long-term bank revolving credit facility of $24,000,000 at December 31, 2002. The terms of the credit facility provide that the loan is due on demand and is subject to annual review. The credit facility has no fixed payment requirements. The amount available for borrowing under the credit facility is reduced by the amount of outstanding letters of credit. Collateral for the loan consists of a demand debenture providing a first floating charge over all of the Trust's assets, and a general security agreement.

Fourteen million dollars of the credit facility carries an interest rate of Canadian chartered bank prime with the balance at one-quarter percent above prime. As of December 31, 2002, the Trust had an outstanding balance under the facility of $10,357,000.

In 2001, the Trust was required under Province of Alberta Regulations to provide a letter of credit in the amount of $1,293,714 to the Alberta Energy and Utilities Board for the future abandonment of specified inactive wells. In 2002, as a result of changes to the Provincial regulations, the Trust was no longer required to provide a letter of credit. The letter of credit was cancelled during 2002.

Included in Bonterra's long-term debt of $18,357,000 at December 31, 2002, is a balance payable of $8,000,000 to Comaplex Minerals Corp. (Comaplex). The interest rate is bank prime less three-quarters of a percent. There currently is no security provided by the Trust for the loan, but the Trust has agreed to maintain a line of credit with its principal banker sufficient to repay the loan if demanded. The loan has been classified as long-term as Comaplex has indicated it will not request repayment within the next 12 months.

The Trust provides an option plan for its directors, officers, employees and consultants. Under the plan, the Trust may grant options for up to 1,323,450 (2001 - 869,223) trust units. The exercise price of each option granted equals the market price of the trust unit on the date of grant and the option's maximum term is five years. Options vest one-third each year for the first three years of the option term. On October 1, 2002, the Trust issued 963,000 unit options to its directors, officers, employees and consultants. The unit options were issued at the market value of the Trust on October 1, 2002, which was $10 per unit and expire January 31, 2007. The unit exercise price does not decline with the Trust's return of capital.

Business Prospects, Risks, and Outlooks

The resource industry operates with a great deal of risk. The most significant risks may come from oil and natural gas price swings, the uncertainty of finding new reserves from drilling programs or acquisitions, competition within the industry, and increasing environmental controls and regulations.

The prices received for crude oil are established by world market forces and for natural gas by forces within North America. Fluctuations in pricing can have extremely positive or negative effects on the Trust's cash flow or in the value of its producing and non-producing oil and natural gas properties.

The Trust presently attempts to minimize these risks by pursuing both oil and natural gas activities and operates its oil and natural gas interests in areas which have long life reserves; where it has the technical expertise to enhance production, control operating costs and to increase margins of profit.

The Trust also maintains an active hedging program. Currently the Trust has forward sales agreements in place for approximately 45 percent on a BOE basis of its estimated 2003 production. The Trust uses a combination of fixed price swaps as well as no cost floors and collars to protect against commodity price declines. During 2002 the Trust incurred a net loss on its hedging of $928,000 as compared to a $1,706,000 hedging gain in 2001. The following schedule outlines the Trusts hedging position post December 31, 2002 as of the printing of this report:

Period of Agreement	Commodity	Volume per day	Index	Price (Cdn.)
January 1, 2003 to March 31, 2003	Crude Oil	900 barrels	WTI	$40.00 per barrel
January 1, 2003 to March 31, 2003	Crude Oil	400 barrels	WTI	$45.10 per barrel
April 1, 2003 to June 30, 2003	Crude Oil	400 barrels	WTI	$40.00 per barrel
April 1, 2003 to June 30, 2003	Crude Oil	600 barrels	WTI	$40.05 per barrel
July 1, 2003 to September 30, 2003	Crude Oil	600 barrels	WTI	$40.06 per barrel
January 1, 2003 to October 31, 2003	Natural Gas	2,000 GJ's	AECO	$3.77 per GJ
January 1, 2003 to March 31, 2003	Natural Gas	1,500 GJ's	AECO	$5.76 per GJ
April 1, 2003 to October 31, 2003	Natural Gas	1,200 GJ's	AECO	$5.82 per GJ
July 1, 2003 to September 30, 2003	Crude Oil	400 barrels	WTI	$45.00 per barrel
October 1, 2003 to December 31, 2003	Crude Oil	600 barrels	WTI	$40.00 per barrel
January 1, 2004 to March 31, 2004	Crude Oil	600 barrels	WTI	$41.00 per barrel
November 1, 2003 to March 31, 2004	Natural Gas	1,800 GJ's	AECO	Floor of $5.00 and ceiling of $9.05 per GJ

Sensitivity Analysis

Sensitivity analysis, as estimated for 2003 follow:

	Cash Flow	Cash Flow Per Unit
U.S. $1.00 per barrel	$ 944,000	$0.074
Canadian $0.10 per MCF	$ 94,000	$0.007
Change of Canadian $0.01/U.S. $ exchange rate	$ 357,000	$0.027

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

The information provided in this report, including the financial statements, is the responsibility of management. In the preparation of the statements, estimates are sometimes necessary to make a determination of future values for certain assets or liabilities. Management believes such estimates have been based on careful judgements and have been properly reflected in the accompanying financial statements.

Management maintains a system of internal controls to provide reasonable assurance that the Trust's assets are safeguarded and to facilitate the preparation of relevant and timely information.

Deloitte & Touche LLP has been appointed by the unitholders to serve as the Trust's external auditors. They have examined the financial statements and provided their auditors' report. The audit committee has reviewed these financial statements with management and the auditors, and has reported to the Board of Directors. The Board of Directors has approved the financial statements as presented in this annual report.

George F. Fink
President & CEO

Garth E. Schultz
Vice President, Finance

AUDITORS' REPORT

To the Unitholders of Bonterra Energy Income Trust:

We have audited the consolidated balance sheets of Bonterra Energy Income Trust as at December 31, 2002 and 2001 and the consolidated statements of unitholders' equity, operations and accumulated income, and of cash flows for the year ended December 31, 2002 and for the period from formation, May 15, 2001, to December 31, 2001. These consolidated financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as, evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2002 and 2001 and the results of its operations and its cash flow for the year ended December 31, 2002 and for the period from formation, May 15, 2001, to December 31, 2001 in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP
Chartered Accountants

Calgary, Alberta
March 26, 2003

Bonterra Energy Income Trust

CONSOLIDATED BALANCE SHEETS

As at December 31 (Note 1)	2002	2001
Assets		
Current		
Accounts receivable	$ 5,895,518	$ 2,670,899
Inventories	321,750	63,367
Prepaid expenses	513,335	354,538
Investments (at cost; quoted market value at December 31, 2002 - $724,166)	460,846	–
	7,191,449	3,088,804
Property and Equipment (Note 3)		
Petroleum and natural gas properties and related equipment	81,608,665	28,909,019
Accumulated depletion and depreciation	(12,382,836)	(5,845,831)
	69,225,829	23,063,188
	$ 76,417,278	$ 26,151,992
Liabilities		
Current		
Bank indebtedness	$ 1,272,866	$ 448,039
Distributions payable	1,470,525	956,144
Accounts payable and accrued liabilities	5,449,301	2,572,360
Current portion of long-term debt (Note 4)	10,357,155	7,889,737
	18,549,847	11,866,280
Long-term debt (Note 4)	8,000,000	–
Future income tax liability (Note 6)	175,478	447,092
Future site restoration	7,800,058	2,450,520
	34,525,383	14,763,892
Unitholders' Equity		
Unit capital (Note 5)	49,607,447	12,975,678
Accumulated earnings	17,840,667	5,366,202
Accumulated cash distributions	(25,556,219)	(6,953,780)
	41,891,895	11,388,100
	$ 76,417,278	$ 26,151,992

On behalf of the Board:

Director

Director

Bonterra Energy Income Trust

CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY

For the Periods Ended December 31 (Note 1)	2002	2001
Unitholders equity, beginning of period (Note 1)	$ 11,388,100	$ 12,975,678
Net earnings for the period	12,474,465	5,366,202
Net capital contributions (Note 1)	36,631,769	–
Cash distributions	(18,602,439)	(6,953,780)
Unitholders' Equity, End of Period	$ 41,891,895	$ 11,388,100

Bonterra Energy Income Trust

CONSOLIDATED STATEMENTS OF OPERATIONS AND ACCUMULATED INCOME

For the Periods Ended December 31 (Note 1)	2002	2001
Revenue		
Oil and gas sales, net of royalties of $3,773,298 (2001 - $712,323)	$ 36,424,209	$ 11,257,362
Production costs	(15,226,323)	(4,097,781)
Alberta royalty tax credits	158,112	34,877
Interest and other	42,421	14,768
	21,398,419	7,209,226
Expenses		
General and administrative	1,243,880	244,803
Management fees	54,000	323,500
Interest on long-term debt	670,933	200,307
	1,968,813	768,610
Cash Flow From Operations Before Current Taxes	19,429,606	6,440,616
Gain on disposal of property	–	294,206
Depletion, depreciation and future site restoration	(7,569,765)	(1,797,984)
Dry holes	–	(4,151)
	(7,569,765)	(1,507,929)
Earnings Before Taxes	11,859,841	4,932,687
Income taxes (recovery) (Note 6)		
Current	(28,103)	(5,518)
Future	(586,521)	(427,997)
	(614,624)	(433,515)
Net Earnings for the Period	$ 12,474,465	$ 5,366,202
Accumulated earnings at beginning of period	5,366,202	–
Accumulated Earnings at End of Period	$ 17,840,667	$ 5,366,202
Net Earnings Per Unit, Basic and Diluted (Note 2)	$ 0.96	$ 0.62

Bonterra Energy Income Trust

CONSOLIDATED STATEMENTS OF CASH FLOW

For the Periods Ended December 31 (Note 1)	2002	2001
Operating Activities		
Net earnings for the period	$ 12,474,465	$ 5,366,202
Items not affecting cash		
Gain on sale of property	–	(294,206)
Depletion, depreciation and future site restoration	7,569,765	1,797,984
Dry holes	–	4,151
Future income taxes	(586,521)	(427,997)
Cash Flow from Operations	19,457,709	6,446,134
Change in non-cash operating working capital items		
Accounts receivable	(583,485)	432,320
Inventories	(132,411)	11,760
Prepaid expenses	169,726	100,834
Accounts payable and accrued liabilities	643,996	(1,859,340)
	97,826	(1,314,426)
	19,555,535	5,131,708
Financing Activities		
Increase in long-term debt	3,717,418	863,274
Unit issue costs	(93,075)	–
Unit distributions payable upon merger	(794,606)	–
Unit distributions	(18,088,056)	(5,997,636)
	(15,258,319)	(5,134,362)
Investing Activities		
Property and equipment expenditures	(5,006,521)	(1,037,085)
Cash received on disposition of property	–	650,000
Bank indebtedness assumed upon arrangement (Note 1)	–	(58,300)
Bank indebtedness assumed upon merger (Note 1)	(115,522)	–
	(5,122,043)	(445,385)
Net cash outflow	(824,827)	(448,039)
Bank indebtedness, beginning of period	(448,039)	–
Bank Indebtedness, End of Period	$ (1,272,866)	$ (448,039)

1. COMMENCEMENT OF TRUST AND BUSINESS COMBINATION

Bonterra Energy Income Trust was formed on May 15, 2001 to effect the arrangement under the Business Corporations Act (Alberta) involving the exchange of the common shares of Bonterra Energy Corp. on a four-for-one basis for units of Bonterra Energy Income Trust. The shareholders of Bonterra Energy Corp. approved the arrangement on June 27, 2001 and Bonterra Energy Income Trust commenced operations on July 1, 2001. The comparative figures disclosed in the financial statements represent operating results for the six month period July 1, 2001 to December 31, 2001. The arrangement is accounted for as a continuation through a restructuring of Bonterra Energy Corp. As a result, the carrying values (see below) of the assets and liabilities of Bonterra Energy Corp. were unaffected by the transaction.

Net Assets Acquired

Current Assets	$ 3,633,688
Property and Equipment	23,488,303
	27,121,991
Current Liabilities	(4,158,064)
Long-term Debt	(7,026,463)
Future Income Taxes	(877,857)
Future Site Restoration	(2,083,929)
	$ 12,975,678

On December 17, 2001, the Trust announced its intention to combine with Comstate Resources Income Trust "Comstate Trust" by way of merger whereby each unit holder of the Trust would receive 0.885 of a unit of Comstate Trust. The transaction was accounted for as a reverse takeover of Comstate Trust by the Trust as the former unitholders of the Trust own greater than 50% of the units of the new trust. The merger arrangement was approved by the unitholders of both Comstate Trust and the Trust on January 24, 2002 and was effective January 31, 2002. As this transaction is accounted for as a reverse takeover, the assets and liabilities of the Trust remain at their book values, while the assets and liabilities of Comstate Trust are recorded at their fair values on January 31, 2002. The net assets of Comstate Trust acquired through this merger transaction were as follows:

Net Non-cash Working Capital	$ 68,048
Bank Indebtedness	(115,522)
Investments	460,846
Property and Equipment	47,696,922
Long-term Debt	(6,750,000)
Future Tax Liability	(314,658)
Future Site Restoration	(4,320,792)
	$ 36,724,844

Trust Units Issued	$ 36,631,769
Unit Issue Costs	93,075
	$ 36,724,844

2. SIGNIFICANT ACCOUNTING POLICIES

Consolidation

These consolidated financial statements include the accounts of the Trust and its wholly owned subsidiaries Bonterra Energy Corp. and Comstate Resources Ltd.

Measurement Uncertainty

The amounts recorded for depletion and depreciation of petroleum and natural gas property and equipment and for future site restoration and reclamation are based on estimates of petroleum and natural gas reserves and future costs. By their nature, these estimates are subject to measurement uncertainty, and the impact on the financial statements of future periods could be material.

Inventories

Inventories consist of materials and supplies that are valued at the lower of cost or net realizable value.

Investments

Investments are carried at the lower of cost and market value.

Property and Equipment

Petroleum and Natural Gas Properties and Related Equipment

The Trust follows the successful efforts method of accounting for petroleum and natural gas properties and related equipment. Costs of acquiring unproved properties are capitalized and amortized on a straight-line basis over the lives of the related leases. These costs are assessed annually for impairment. When property is found to contain proved reserves as determined by the Trust's engineers, the related net book value is depleted on the unit-of-production basis, calculated by field. The costs of dry holes and abandoned properties are charged to operations. Geological costs, lease rentals and carrying costs are charged to income as incurred. Costs of drilling exploratory and development wells that result in additions to proved reserves are capitalized and depleted on the unit-of-production basis. Tangible equipment is depreciated on a straight-line basis over ten years.

Furniture, Fixtures and Office Equipment

These assets are recorded at cost and depreciated over a three to ten year period representing their estimated useful lives.

Income Taxes

The Trust follows the liability method of accounting for income taxes under which the income tax provision is based on the temporary differences in the accounts calculated using income tax rates expected to apply in the year in which the temporary differences will reverse.

Future Site Restoration

The Trust provides for future site restoration and abandonment costs over the estimated production life of its property

and equipment. Estimates of these amounts are based on the anticipated method and extent of site restoration using current costs and in accordance with existing legislation and industry practice. The annual charge is included with depletion, depreciation and future site restoration.

Trust-Unit-Based Compensation Plan

The Trust has a trust-unit-based compensation plan, which is described in Note 5. No compensation expense is recognized for these plans when unit options are issued to employees or directors at the prevailing market prices. Any consideration paid by service providers on the exercise of theses options is recorded as unit capital. For options issued after January 1, 2002, the fair values are determined and the impact on earnings if applicable is disclosed as pro forma information.

Revenue Recognition

Petroleum and natural gas sales are recognized when the commodities are delivered to purchasers.

Hedging

The Trust uses derivative instruments to reduce its exposure to fluctuations in commodity prices and foreign exchange rates. Gains and losses on these contracts, all of which constitute effective hedges, are recognized as a component of oil and gas sales.

Joint Interest Operations

Significant portions of the Trust's oil and gas operations are conducted with other parties and accordingly the financial statements reflect only the Trust's proportionate interest in such activities.

Net Earnings Per Unit

Basic earnings per unit are computed by dividing earnings by the weighted average number of units outstanding during the period. Diluted per unit amounts reflect the potential dilution that could occur if options or warrants to purchase trust units were exercised. The treasury stock method is used to determine the dilutive effect of trust unit options and warrants, whereby proceeds from the exercise of trust unit options or other dilutive instruments are assumed to be used to purchase trust units at the average market price during the period.

The number of trust units used to calculate diluted net earnings per unit for the period ended December 31, 2002 was 12,978,723 (2001 - 8,692,226). The number of units used to calculate diluted net earnings per unit discussed above did not include 240,750 (2001 - Nil) of unit options on a weighted average basis, as the effect would be anti-dilutive.

3. PROPERTY AND EQUIPMENT

	2002		2001	
Undeveloped Land	$ 64,632	$ –	$ 461,215	$ –
Petroleum and natural gas properties and related equipment	80,907,617	12,276,863	28,422,237	5,834,969
Furniture, equipment and other	636,416	105,973	25,567	10,862
	$ 81,608,665	$ 12,382,836	$ 28,909,019	$ 5,845,831

During the period $35,803 (2001 - Nil) of general and administrative expenses were capitalized.

At December 31, 2002, the estimated future site restoration costs to be accrued over the life of the remaining proved reserves are $18,944,765 (2001 - $17,658,528)

4. LONG-TERM DEBT

The Trust has a long-term bank revolving credit facility of $24,000,000 at December 31, 2002 (2001 - $10,000,000). The terms of the credit facility provide that the loan is due on demand and is subject to annual review. The credit facility has no fixed payment requirements. The amount available for borrowing under the credit facility is reduced by the amount of outstanding letters of credit. Collateral for the loan consists of a demand debenture providing a first floating charge over all of the Trust's assets, and a general security agreement.

Fourteen million dollars of the credit facility carries an interest rate of Canadian chartered bank prime with the balance at one-quarter percent above prime. As of December 31, 2002, the Trust had an outstanding balance under the facility of $10,357,155. The Trust has classified borrowing under its bank facilities as a current liability as required by new guidance under the CICA's Emerging Issues Committee Abstract 122. It has been management's experience that these types of loans which are now required to be classified as a current liability are seldom called by principal bankers as long as all the terms and conditions of the loan are complied with. The bank loan at December 31, 2001 has been restated to conform to current presentation. Cash interest paid during the period ended December 31, 2002 for this loan was $398,499 (six months ended December 31, 2001 - $182,858).

The Trust was required under Province of Alberta Regulations to provide a letter of credit in the amount of $1,293,714 to the Alberta Energy and Utilities Board for the future abandonment of specified inactive wells. In 2002, as a result of changes to the Provincial regulations, the Trust was no longer required to provide a letter of credit. The letter of credit was cancelled during the second quarter.

As at December 31, 2002, the Trust has a balance payable of $8,000,000 to Comaplex Minerals Corp. (Comaplex) a company with common management (see note 9). The interest rate is bank prime less three-quarters of a percent. There currently is no security provided by the Trust for the loan, but the Trust has agreed to maintain a line of credit with its principal banker sufficient to repay the loan if demanded. The loan has been reclassified as long-term as Comaplex has indicated it will not request repayment within the next 12 months. Cash interest paid during the twelve months ended December 31, 2002 for this loan was $269,346.

5. UNIT CAPITAL

Authorized

The Trust is authorized to issue an unlimited number of trust units without nominal or par value

	2002		2001	
Issued	Number	Amount	Number	Amount
Trust Units				
Balance, beginning of period (Note 1)	8,692,226	$ 12,975,678	8,692,226	$ 12,975,678
Issued on Merger with Comstate Resources Income Trust (Note 1)	4,676,179	36,631,769	–	–
Balance, end of period	13,368,405	$ 49,607,447	8,692,226	$ 12,975,678

The Trust provides an option plan for its directors, officers, employees and consultants. Under the plan, the Trust may grant options for up to 1,323,450 (2001 - 869,223) trust units. The exercise price of each option granted equals the market price of the trust unit on the date of grant and the option's maximum term is five years. Options vest one-third each year for the first three years of the option term. On October 1, 2002, the Trust issued 963,000 unit options to its directors, officers, employees and consultants. The unit options were issued at the market value of the Trust on October 1, 2002, which was $10 per unit and expire January 31, 2007.

The Trust accounts for its stock based compensation plan using intrinsic values. Under this method no costs are recognized in the financial statements for unit options granted to employees and directors when the options are issued at prevailing market prices. For fiscal years beginning on or after January 1, 2002, Canadian generally accepted accounting principles require disclosure of the impact on net earnings using the fair market value method for stock options issued on or after January 1, 2002. If the fair value method had been used, the Trust's net earnings and net earnings per unit would not be significantly different from those reported. The fair value of options granted has been estimated using the Black-Scholes option pricing model, assuming a risk free interest rate of 4.20%, expected volatility of 25%, expected weighted average life of five years and an annual dividend rate based on the distributions paid to the unitholders during the year.

6. INCOME TAXES

The Trust has recorded a future income tax liability. The liability relates to the following temporary differences:

	2002	2001
Temporary differences related to assets and liabilities	$ 801,425	$ 723,315
Finance expense charged to unitholders' equity	(150,160)	(103,263)
Tax loss carry forward	(475,787)	(172,960)
	$ 175,478	$ 447,092

Income tax expense varies from the amounts that would be computed by applying Canadian federal and provincial income tax rates as follows:

	2002	2001
Earnings before income taxes	$ 11,859,841	$ 4,932,687
Combined federal and provincial income tax rates	42.75%	43.26%
Income tax provision calculated using statutory tax rates	5,070,082	2,133,880
Increase (decrease) in income taxes resulting from:		
Non-deductible crown royalties	1,391,837	293,072
Resource allowance	(2,476,610)	(746,038)
Trust income allocated to unitholders	(4,489,166)	(1,991,107)
Non-taxable gain on deemed disposition of subsidiary	–	(127,763)
Income tax rate reduction	(44,082)	–
Income tax recovery	(28,103)	–
Other	(38,582)	4,441
	$ (614,624)	$ (433,515)

The Trust and its subsidiaries have the following tax pools, which may be used to reduce taxable income in future years, limited to the applicable rates of utilization:

	Rate of Utilization %	Amount
Undepreciated capital costs	20-100	$ 4,956,396
Canadian oil and gas property expenses	10	21,593,507
Canadian development expenses	30	325,110
Canadian exploration expenses	100	1,334,947
Income tax losses	100	1,124,702
Finance expenses	20	551,951
		$ 29,886,613

7. FINANCIAL INSTRUMENTS

Fair Values

The Trust's financial instruments included in the balance sheets are comprised of accounts receivable and current liabilities, including the revolving demand loan and the loan payable to Comaplex. The fair values of these financial instruments approximate their carrying value due to the short-term maturity of those instruments. Borrowings under bank credit facilities and the Comaplex loan are for short periods with variable interest rates, thus, carrying values approximate fair value.

Credit Risk

Substantially all of the Trust's accounts receivable are due from customers in the oil and gas industry and are subject to normal industry credit risks. The carrying value of accounts receivable reflects management's assessment of associated credit risks.

Interest Rate Risk

The Trust's bank debt which is comprised of a revolving loan and the Comaplex loan are at a variable rate and as such the Trust is exposed to interest rate risk.

Commodity Price Risk

The nature of the Trust's operations results in exposure to fluctuations in commodity prices and exchange rates. The Trust monitors and when appropriate uses derivative financial instruments to manage its exposure to these risks.

8. COMMITMENTS

The Trust entered into the following commodity hedging transactions in 2002 for a portion of its 2003 production:

Period of Agreement	Commodity	Volume per day	Index	Price (Cdn.)
January 1, 2003 to March 31, 2003	Crude Oil	900 barrels	WTI	$40.00 per barrel
January 1, 2003 to March 31, 2003	Crude Oil	400 barrels	WTI	$45.10 per barrel
April 1, 2003 to June 30, 2003	Crude Oil	400 barrels	WTI	$40.00 per barrel
April 1, 2003 to June 30, 2003	Crude Oil	600 barrels	WTI	$40.05 per barrel
July 1, 2003 to September 30, 2003	Crude Oil	600 barrels	WTI	$40.06 per barrel

January 1, 2003 to October 31, 2003	Natural Gas	2,000 GJ's	AECO	$3.77 per GJ
January 1, 2003 to March 31, 2003	Natural Gas	1,500 GJ's	AECO	$5.76 per GJ
April 1, 2003 to October 31, 2003	Natural Gas	1,200 GJ's	AECO	$5.82 per GJ

9. RELATED PARTY TRANSACTIONS

The Trust has guaranteed $3,000,000 of a loan to Novitas Energy Ltd. (Novitas), a former subsidiary of the Trust and a company with common management. In consideration for the guarantee Novitas has entered into a management agreement whereby the Trust will provide all management services on a fee for service basis.

During 2002, the Trust received a management fee from Novitas for management services of $5,000 per month plus five percent of before tax income. Total receipts during 2002 were $68,000 (2001 - Nil) and have been included as a recovery of general and administrative expenses.

Novitas also paid administrative fees on a per well basis to the Trust for the administration of its oil and gas properties. Total amount paid during 2002 was $128,500 (2001 - Nil). This amount has also been recorded as a recovery of general and administrative expenses.

The Trust received a management fee from Comaplex of $110,000 (2001 - Nil) for management services and office administration. This cost has been included as a recovery in general and administrative expenses.

10. MANAGEMENT AGREEMENT

Prior to its merger on February 1, 2002 with Comstate Trust, the Trust had entered into a management agreement with Comstate Resources Ltd. (Comstate) a 100% owned subsidiary of Comstate Trust. Fees charged for field operations were charged on a per well basis. Total amount charged during 2002 was $68,140 (2001 - $394,020). This amount, net of amounts related to joint venture partner interests, has been recorded in production costs.

Fees for management and general office services consisted of $30,000 per month plus three percent of before tax net income. The total amount paid during the period was $54,000 (2001 - $326,230) and has been included in general and administrative expenses.

Effective February 1, 2002, Comstate became a wholly owned subsidiary of the Trust and the Trust is no longer charged a management fee.

11. SUBSEQUENT EVENT – COMMITMENTS

The Trust entered into the following commodity hedging transactions subsequent to December 31, 2002 for a portion of its future production:

Period of Agreement	Commodity	Volume per day	Index	Price (Cdn.)
July 1, 2003 to September 30, 2003	Crude Oil	400 barrels	WTI	$45.00 per barrel
October 1, 2003 to December 31, 2003	Crude Oil	600 barrels	WTI	$40.00 per barrel
January 1, 2004 to March 31, 2004	Crude Oil	600 barrels	WTI	$41.00 per barrel
November 1, 2003 to March 31, 2004	Natural Gas	1,800 GJ's	AECO	Floor of $5.00 and ceiling of $9.05 per GJ

TRUST INFORMATION

Head Office 901, 1015 – Fourth Street SW Calgary, Alberta T2R 1J4 PH 403.262.5307 FX 403.265.7488

Board of Directors

Officers

G.F. Fink – President & CEO

R.M. Jarock – Operations Manager & Vice President, Corporate Development

S.L. Safronovitch – Vice President Operations

G.E. Schultz – Vice President, Finance & Secretary

Registrar & Transfer Agent

Olympia Trust Company, Calgary, Alberta

Auditors

Deloitte & Touche LLP, Calgary, Alberta

Solicitors

Parlee McLaws, Calgary, Alberta

Tupper, Jonsson & Yeadon, Vancouver, British Columbia

Bankers

The Royal Bank of Canada, Calgary, Alberta

Stock Listing

The Toronto Stock Exchange, Toronto, Ontario

Trading symbol: BNE.UN

Web Site

www.bonterraenergy.com

Bonterra
Energy Income Trust

BONTERRA ENERGY INCOME TRUST, 901, 1015 – 4TH STREET SW, CALGARY, ALBERTA T2R 1J4